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AZ CORP COMMISSION
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Docket Control
Arizona Corporation Commission
1200 W Washington
Phoenix, AZ 85007

RE: Resource Planning and Procurement in 2011 and 2012 – Docket No. E-00000A-11-0113

Dear Sir/Madam:

The Interstate Renewable Energy Council, Inc. (IREC), appreciates the opportunity to comment on the Integrated Resource Plans, and related processes, filed in the above referenced docket. Please feel free to contact me at (602) 388-4640 if you have any questions.

Sincerely,

Giancarlo Estrada

Arizona Corporation Commission
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Comments of the Interstate Renewable Energy Council on Integrated Resource Planning, Docket No. E-00000A-11-0113

The Interstate Renewable Energy Council ("IREC") respectfully submits these comments to the Arizona Corporation Commission regarding Integrated Resource Planning, Docket No. E-00000A-11-0113. Arizona Public Service ("APS") and Tucson Electric Power ("TEP") should be commended for their work on providing thoughtful and detailed Integrated Resource Plans ("IRP"). While not disputing the companies' general approach, several issues have emerged from the plans and subsequent meetings that deserve additional attention.

1. The Commission should acknowledge APS' and TEP's IRPs with modifications. In APS' case, this acknowledgement should recognize the strong support among stakeholders for the "Enhanced Renewables" option.

We agree with the Staff consultant's recommendation to acknowledge the IRPs filed by APS and TEP. However, we urge the Commission to make this acknowledgement contingent on modifications that respond to the comments included herein. Furthermore, this acknowledgement should include some indication of general resource portfolio preference. Although a statement of preference may not be required, it would ensure that the IRP process provides maximum benefit to participating stakeholders. Through the workshop and subsequent comments, stakeholders have generally voiced their strongest support for the "Enhanced Renewables" portfolio option in APS' IRP. We urge the Commission to recognize the support for this option in their acknowledgement.

2. APS' resource cost comparison conflates different resource attributes (energy, capacity, and operational flexibility) that should each be considered separately

Analysis of the incremental cost of resource additions was discussed extensively in a workshop held at the Arizona Corporation Commission on August 22, 2012. Of particular interest was the chart in Figure 13 of APS' IRP, later updated in this docket, showing a $/MWh-delivered (levelized cost of energy) comparison of different energy resources. This chart purports to compare resources "apples to apples" and to construct resource portfolios for each of the four scenarios in APS' IRP. While insightful, this chart relies on a flawed approach which does not yield a true "apples to apples" comparison.

In planning for the future resource mix, APS considers energy, capacity and flexibility of resources. Each resource option provides a different measure of these attributes. For instance, renewable resources are often a superior substitute for conventional resources for producing energy since they have no fuel costs. Meanwhile, renewable resources can also provide substitute capacity from conventional resources, although they are an inferior substitute since the output is typically diminished a peak times. Finally, *both* renewable resource *and* conventional baseload resources (e.g. coal, nuclear) lack flexibility since they cannot be dispatched quickly to meet real time fluctuations in supply or demand; thus these inflexible resources must be complemented by flexible generation resources such as combustion turbines ("CTs").

Figure 13 of APS' IRP attempts to value all three of these attributes in a single chart by equating the cost of capacity and flexibility (also referred to as "integration") to the cost of energy. However in our view a more appropriate analysis should consider each of these attributes separately since the need for each attribute will vary as the characteristics of the larger power system evolve over time.

APS should specify what present or future constraints are driving the need for each particular attribute. For example, in assessing capacity value for a resource, APS needs to indicate how close it is to reaching a specified planning reserve margin.[1] If nearing this margin is not imminent, the capacity value provided by the resource should be appropriately discounted. Consequently, the need to "firm" resources with capacity values below 100% should be diminished as well. During the August 22, 2012 workshop, APS stated that firming costs were added to wind and solar equal to 80 percent and 30 percent, respectively, of a CT unit. This additional cost is at odds with the fact that capacity need does not materialize for several years.

3. APS should clarify for stakeholders that the addition of renewable resources does not, on its face, lead to a need for additional conventional resources as backup reserves

During the August 22 IRP stakeholder workshop, several questions were raised about the need for backup power to firm and integrate variable renewable resources. For instance, in one exchange, a question was posed about whether an increase from 100 MW to 1000 MW of solar resources on APS 'system would lead to an increase, a decrease, or unknown change in the need for additional CTs. The answer to this question is complex and depends on specific system characteristics. In general though, renewable resources *do not* require MW per MW backup generation. The misconception that renewable resources need one to one backup capacity is increasingly common in resource planning forums around the country and should be dispelled in Arizona's present IRP process. Going forward, APS and other utilities should take greater care to explain how generation and load are balanced on a system-wide basis, rather than for individual resources or resource groups and as such, reserve capacity need does not scale up in a linear fashion. Furthermore, APS should demonstrate whether or not the addition of renewable resources drives either of the following conditions that may require the addition of *some* (a lesser amount) conventional generation capacity: 1) lack of flexible, fast-ramping capacity 2) lack of contingency reserves.

3.1 Lack of flexible capacity (i.e. regulation and spinning reserves):

The addition of renewable resources can never increase the capacity required to serve load *unless* the existing generation fleet cannot respond quickly enough. Going forward, APS should provide some indication of how close it may be to exhausting necessary flexible, fast-ramping generation capacity needed to integrate and inflexible resources (both variable and baseload) as they come online. APS should identify needs in the context of their own resources, as well as other options such as an Energy Imbalance Markets ("EIM") or dynamic transfers not requiring he installation of additional APS-owned capacity.

3.2 Lack of contingency reserves (i.e. replacement reserves):

[1] For instance, the most recent analysis by WECC indicates that the Desert Southwest Region (which includes APS) will have sufficient resource capacity to maintain a 15% planning reserve margin through 2019 (See: https://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/2011%20Power%20Supply%20Assessment.aspx). APS states in its IRP that it will need additional capacity for its own system as soon as 2016 depending on the outcome of the Four Corners transaction.

solutions for providing this same firming capacity, including energy efficiency, demand response, short-term contracts among other options.

4.2 Integration Costs

APS estimates a solar integration cost of $2.50/MWh, based upon a 2009 study by the Western Governors' Association.[5] However, APS does not properly qualify its use of the $2.50 value for integration costs. The $2.50/MWh number is derived from a default input value in the Generation and Transmission Model ("GTM") developed by the National Renewable Energy Laboratory ("NREL") as a starting point and needs appropriate tailoring.

To be fair, APS noted in the plan that it was undertaking an effort to update this number in the first half of 2012. We applaud APS for seeking to provide more accurate and up to date information on renewable resource integration. If the updated information is already available, the IRP should be updated to reflect that change. Additionally, if integration costs specific to APS cannot be provided at this time, APS should conduct a sensitivity analysis on the $2.50/MWh value to reflect the full range of possible values based on the industry's current knowledge of renewable resource integration. Indeed there is sufficient evidence that integration costs could be much lower or higher than what APS has indicated in its IRP. Comparative studies show that integration costs for wind range from 45 cents per MWh to $8.84 per MWh.[6]

5. Overestimating firming and integration costs could significantly harm ratepayer interests and lead to higher rates than necessary

If firming and integration costs turn out to be lower than what is currently represented in the IRP, it is possible that solar would emerge as the least-cost supply-side resource (excluding energy efficiency). This could fundamentally alter APS' energy procurement strategy going forward. Failure to recognize this possibility could lead to overinvestment in more costly forms of generation than necessary and ultimately lead to customers paying more than a just and reasonable rate for electricity. We believe that APS should provide an indication of how its resource procurement pathway might change if integration and firming costs are significantly reduced (e.g. to the point where incremental solar is equal to, or less costly than incremental combined cycle natural gas). Furthermore, this analysis would ideally indicate what impact this alternate procurement pathway would have on future revenue requirements.

Additionally, if APS does not sufficiently explore efficient reserve management through opportunities such as energy imbalance markets, dynamic transfers, or intra-hour scheduling, it may similarly lead planners to overbuild conventional generation resources and potentially increase customer rates beyond what's needed.

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[5] Western Governors' Association Generation and Transmission Model Methodology and Assumptions, Version 2.0, June 2009.

[6] Wind Energy and Power System Operations: A Review of Wind Integration Studies to Date, 2009, http://www.nrel.gov/wind/systemsintegration/pdfs/2009/porter_integration_studies_review.pdf APS was also included in this study with an integration cost of $4.08 for a wind capacity penetration of 15%, which is not realistic for the purposes of the IRP, but perhaps is indicative of an upper bound of integration costs APS might face in the near term.

6. Each IRP should include information about the costs and benefits of an Energy Imbalance Market ("EIM"), Dynamic Transfers, and Intra-hour Scheduling on future integration costs

Through the IRP process, affected utilities such as APS should be encouraged to participate robustly in the investigation of the creation of an Energy Imbalance Market ("EIM") and should ultimately participate in an EIM if it is proven to provide value to Arizona ratepayers and reduce integration costs for renewable energy. Preliminary analysis of a potential West-wide EIM showing benefits from the adoption of an EIM by the state's two largest ACC-regulated utilities in excess of $35 million.[7] It is reasonable to assume that the Commission would ultimately pass those savings on to ratepayers in the form of lower rates and charges

The PUC EIM group has not yet fully completed its work, and analysis on the costs and benefits of an EIM are ongoing; however, affected utilities should be required by the Commission to report on the progress of an EIM as part of the IRP process, and should indicate as part of their IRP filings how an EIM would affect the integration costs that are currently being ascribed to renewable energy by the affected utilities.

In addition to considering an EIM as a method for reducing integration costs, affected Arizona utilities should examine the efficacy of increased use of dynamic transfer to reduce integration costs and increase efficiencies. While dynamic transfer requires a fair amount of utility-to-utility cooperation and coordination, it may facilitate delivery of energy without having to build large amounts of additional transmission. As with EIM, the Commission should require that affected utilities indicate as part of their IRP filings how dynamic scheduling would impact integration costs for renewable resources, and how the use of dynamic scheduling could reduce energy costs more broadly for the utility.

7. APS' levelized cost comparison is appropriate, but also obscures some implications resource choices may have on future customer rates and investor returns

We believe that the levelized cost of energy (LCOE) is a useful and appropriate measure for comparing between energy resources. However, there are some crucial details that are not readily apparent when using an LCOE analysis that APS should strive to make more transparent in its IRP. The most important of these is that since costs are averaged over a period of time (while appropriately discounting for the time-value of money), LCOE gives little indication of how the year-to-year revenue requirements vary for investments in different types of resources. The Chart in Attachment A reconstructs the annual revenue requirements (in $/kWh) and LCOE values for a solar PV resource using information from the APS IRP. The same is done for the equivalent in costs avoided by installing the PV system in terms of energy and capacity offered by an equivalent combustion turbine natural gas unit, consistent with APS' approach. It's readily apparent that the revenue requirement for the avoided resource (i.e. an equivalent CT unit) steadily increases, while the revenue requirement for the PV resource steadily decreases. Thus while the LCOE for each resource is similar, the annual revenue requirement quickly diverges. This divergence is largely due to the forecasted price of natural gas and its impact on the operational cost component of the CT's revenue requirement. Many uncertainties surround forecasts of fuel

[7] See http://www.westgov.org/PUCeim/meetings/present/nrel.pdf

costs, which are often controversial and were widely discussed in the August 22 workshop. Yet the contrast reveals a simple fact: solar PV presents less uncertainty about future operating costs since it is predominately a fixed capital cost that depreciates over time. On a portfolio level, the Enhanced Renewable and Coal Retirement scenarios have lower revenue requirements than the base case in the long run (see ATT-89 of APS' IRP), in part due to the investment in renewable resources and subsequent reduction in long-term fuel costs.

8. APS consideration of "diminished capacity value" for solar requires further detail to be considered relevant to the current IRP process

APS spent considerable time at the August 22 workshop to explain a phenomenon described as "diminished capacity value." To summarize, increased penetration of solar resources on APS' system has the net effect of reducing the capacity value of future incremental solar since the peak hour is shifted to a later hour. We appreciate APS' forward-thinking approach in anticipating this important impact of renewable energy on its system. However, APS gave few details on the magnitude of this shift, nor how quickly it would occur based on current trajectory of solar resource additions. Indeed, studies on the capacity value of solar in Arizona have shown that even high penetrations of PV solar on the order 15 percent still show capacity values on the order of 40-50 percent.[8] Additionally, APS current investment in CSP with thermal storage through the Solana project should mitigate some of the diminished capacity value from solar as well. Finally, APS needs to address how load-shaping opportunities such as demand response and peak pricing might mitigate the effect. Until APS can provide more details on the relative impact of this diminished capacity value over the IRP's planning horizon, it may be premature to consider the significance of this effect.

9. Distributed energy deployment is not fully considered in APS' plan

APS' assumptions about distributed generation leave many unanswered questions about the nature of this resource in the coming years. Indeed, while the level of overall distributed energy was specified, APS provides no indication of how this overall level of distributed energy will be deployed. More detail on the composition of the future distributed energy market would be helpful for stakeholders since this has a direct impact on the costs and relative incentive levels required. A recent study commissioned by APS[9] revealed the potential for distributed energy to defer future capital costs including new transmission and distribution infrastructure. These effects should be addressed in the IRP to give stakeholders some sense of the magnitude of infrastructure deferrals possible under a highly distributed energy scenario.

10. The alternative scenarios evaluated in APS' IRP are insufficiently distinct from the Base Case

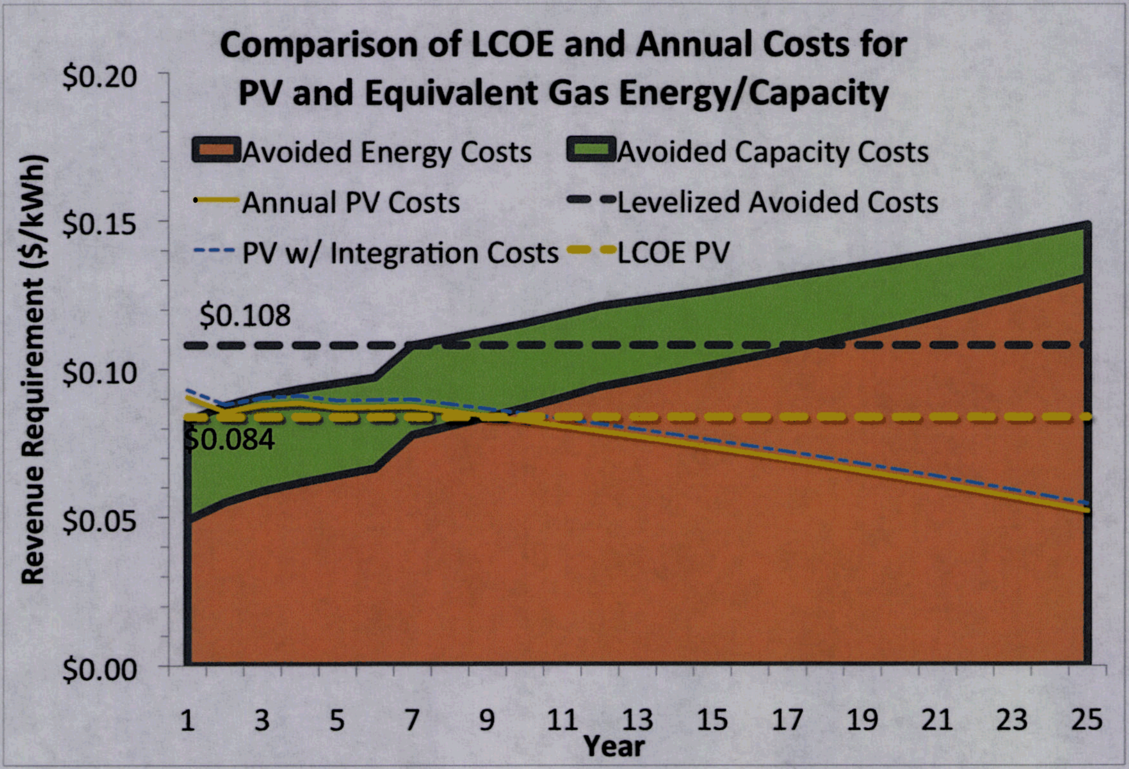
The annual revenue requirements in each of the four scenarios presented by APS are largely similar. The net present value revenue requirement (2012-2027) for each of the

[8] See http://www.nrel.gov/docs/fy06osti/40068.pdf

[9] R.W. Beck, Distributed Renewable Energy Operating Impacts & Valuation Study, 2009. http://www.aps.com/_files/solarRenewable/DistRenEnOpImpactsStudy.pdf

three alternatives scenarios ranged from an increase above the base case of as little as 1 percent to as much as 4 percent. With such little variation between the scenarios it is difficult to distinguish the true impact of resource choices on costs over the long term. Since the IRP does not dictate procurement it would helpful to stakeholders for APS to explore additional scenarios that are perhaps less plausible, and not intended to be implemented, but are intended to illustrate more starkly the impact resource choices have on future costs and other outcomes. For example, one could envision a hypothetical "all renewables" case or an "all gas" case. Furthermore, an "enhanced EE" scenario would be a logical complement to the existing "enhanced RE" scenario. Additionally, a "high distributed energy" scenario would be illustrative for the costs and benefits of growing the customer-generation fraction of the resource portfolio.

ATTACHMENT A



Modeled Assumptions

Category	Variable	Value	Source
Solar PV Assumptions (Thin Film - SAT)	Capital Cost	$1,998/kW-dc	APS IRP ATT-69
	dc-ac Derate Factor	0.77	NREL -- PV WATTS
	Fixed O&M	$25/kW-yr	APS IRP ATT-69
	Var O&M	$0/MWh	APS IRP ATT-69
	Capacity Factor	29%	APS IRP ATT-69
	Useful Life	25 years	APS IRP ATT-69
	Degradation Factor	1%/year	Assumed
Avoided Capacity Cost Assumptions (LMS 100PA High Temp, Low Water)	Capital Cost	$1,012/kW-ac	APS IRP ATT-68
	PV System Capacity Value	70%	APS IRP ATT-69
	PV System Availability	98%	NREL -- PV WATTS
	Fixed O&M	$5.20/kW-yr	APS IRP ATT-68
Avoided Energy Cost Assumptions	Var O&M	$4.86/MWh	APS IRP ATT-68
	Marginal Heat Rate for Energy Displaced by PV	10,000 BTU/kWh	Assumed based on APS IRP ATT-29
	Fuel Price 2012-2027	$4.42/MMBTU increasing to $8.56 in year 15	APS IRP ATT-30
	Fuel Price 2027-2037	+2%/year	Assumed
	Emissions (Carbon) Cost	$15/ton in 2019, increasing 5% annually	APS IRP Page 42
	Degradation Factor	1%/year	Assumed
Financial Assumptions	Discount Rate (After-tax weighted cost of capital)	7.95%	APS IRP Table 14 (p 83)
	Income tax rate	40%	APS IRP Table 14 (p 83)
	30% ITC Expiration	2016	APS IRP Table 14 (p 83)
	Solar PV Tax Life	5 years	APS IRP Table 14 (p 83)
	CT Tax Life	15 years	APS IRP Table 14 (p 83)